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Effective detection of CO₂ leakage: a comparison of groundwater sampling and pressure monitoring

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Abstract

Shallow aquifer monitoring is likely to be a required aspect to any geologic CO₂ sequestration operation. Collecting groundwater samples and analyzing for geochemical parameters such as pH, alkalinity, total dissolved carbon, and trace metals has been suggested by a number of authors as a possible strategy to detect CO₂ leakage. The effectiveness of this approach, however, will depend on the hydrodynamics of the leak-induced CO₂ plume and the spatial distribution of the monitoring wells relative to the origin of the leak. To our knowledge, the expected effectiveness of groundwater sampling to detect CO₂ leakage has not yet been quantitatively assessed. In this study we query hundreds of simulations developed for the National Risk Assessment Project (US DOE) to estimate risks to drinking water resources associated with CO₂ leaks. The ensemble of simulations represent transient, 3-D multi-phase reactive transport of CO₂ and brine leaked from a sequestration reservoir, via a leaky wellbore, into an unconfined aquifer. Key characteristics of the aquifer, including thickness, mean permeability, background hydraulic gradient, and geostatistical measures of aquifer heterogeneity, were all considered uncertain parameters. Complex temporally-varying CO₂ and brine leak rate scenarios were simulated using a heuristic scheme with ten uncertain parameters. The simulations collectively predict the spatial and temporal evolution of CO₂ and brine plumes over 200 years in a shallow aquifer under a wide range of leakage scenarios and aquifer characteristics.

Using spatial data from an existing network of shallow drinking water wells in the Edwards Aquifer, TX, as one illustrative example, we calculated the likelihood of leakage detection by groundwater sampling. In this monitoring example, there are 128 wells available for sampling, with a density of about 2.6 wells per square kilometer. If the location of the leak is unknown *a priori*, a reasonable assumption in many cases, we found that the leak would be detected in at least one of the monitoring wells in less than 10% of the scenarios considered. This is

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because plume sizes are relatively small, and so the probability of detection decreases rapidly with distance from the leakage point. For example, 400m away from the leakage point there is less than 20% chance of detection.

We then compared the effectiveness of groundwater quality sampling to shallow aquifer and/or reservoir pressure monitoring. For the Edwards Aquifer example, pressure monitoring in the same monitoring well network was found to be even less effective than groundwater quality monitoring. This is presumably due to the unconfined conditions and relatively high permeability, so pressure perturbations quickly dissipate. Although specific results may differ from site to site, this type of analysis should be useful to site operators and regulators when selecting leak detection strategies. Given the spatial characteristics of a proposed monitoring well network, probabilities of leakage detection can be rapidly calculated using this methodology.

Although conditions such as these may not be favorable for leakage detection in shallow aquifers, leakage detection could be much more successful in the injection reservoir. We demonstrate proof-of-concept for this hypothesis, presenting a simulation where there is measurable pressure change at the injection well due to overpressurization, fault rupture, and consequent leakage up the fault into intermediate and shallow aquifers. The size of the detectible pressure change footprint is much larger in the reservoir than in either of the overlying aquifers. Further exploration of the range of conditions for which this technique would be successful is the topic of current study.

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Keywords:

1. Introduction

A critical component of any successful geologic carbon sequestration project will be to assure stakeholders and regulators that the risk of leakage out of the sequestration reservoir is very low *and*, if a leak were to occur, the event could be detected. This paper addresses the issue of leakage detection. Active research is being conducted for a variety of methods, including above ground CO₂ flux monitoring, shallow and intermediate aquifer groundwater chemistry monitoring, pressure monitoring (both above and within the injection reservoir), and seismic monitoring. In this study we compare two specific methods: water chemistry monitoring in wells completed in a shallow aquifer above the reservoir and pressure monitoring both above and within the injection reservoir.

Monitoring shallow aquifer chemistry is an important method to consider because EPA Class VI injection well permitting requires the site operator to demonstrate that USDW (Underground Source of Drinking Water) are not impacted. The Class VI Rule and related documents are available at http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm. Important questions remain, however, concerning the likelihood that monitoring groundwater quality might lead to false positives (chemical changes unrelated to CO₂ leakage) or false negatives (leakage which cannot be detected using this method).

Pressure monitoring in the reservoir is standard protocol in oil and gas production, geothermal operations, and CO₂ injection pilot studies. The potential for pressure monitoring within and/or above the reservoir to signal a 'leakage event' has been studied by several authors [1-5]. These studies clearly demonstrate that the effectiveness of the method depends heavily on factors including reservoir properties (particularly heterogeneity), 'noise' in the reservoir, the size and time-evolution of the leak, and distance between the leak and the pressure monitoring point. It is difficult to generalize these results to all possible reservoir types and leakage scenarios.

In this study, we restrict our consideration to a very specific class of leakage monitoring scenarios. We envision the case where the monitoring well network (used to measure either pressure or water chemistry) was designed *without* prior knowledge of the location of the ultimate leakage pathway. In this case, the probability of detection is a relatively simple function of the size and magnitude of the leakage-related perturbation and the density of the monitoring detection. This is an important case to consider since the possibility of previously 'unknown' leakage pathway is always present. The difficulty of predicting exactly where a CO₂ leak will emerge was highlighted in a recent controlled release experiment [6].

2. Method

The proposed method defines a probability of detection for a given leak as a function of the distance between the monitoring well and the leakage feature. This probability is calculated as a joint probability of two uncorrelated probability functions; illustrated conceptually in Figure 1. The blue line is only related to the dimensions of the leakage perturbation (chemistry change or pressure change); the red line is related to the density of the monitoring well network. The green line is the joint probability distribution, expressing the likelihood that a leak would be detected. For this conceptual example, the most likely detection scenario would be a well about 400 m from the leak. At best, there would be about a 40% chance of detection

We utilized two sets of multi-phase flow simulations to investigate what these

probabilities might be for realistic reservoir and/or aquifer leakage scenarios. The first two sets of simulations were originally generated for the purpose of probabilistic risk assessment

[7,8,9]; these results were easily queried to derive detection probabilities for this study. These simulations were designed to investigate physical and chemical changes in a shallow unconfined carbonate aquifer due to a single-point CO₂ leakage. Site-specific data collected in an unconfined portion of the Edwards Aquifer north of San Antonio, TX, USA were used to establish the hydrogeologic setting [10,11]. The 3-D multi-phase flow reactive transport simulations were developed using the FEHM code [12]; further details of the simulations can be found in [7,8,9].

A third set of simulations were designed specifically for the purpose of comparing the efficacy of pressure monitoring in the shallow aquifer versus the injection reservoir. These 2-D simulations [13] were used to predict pressure changes caused by the rupture of an overpressured fault zone in the injection reservoir. During CO₂ injection, if a critical pressure threshold is reached, the fault zone ruptures and the permeability of the conduit instantaneously increases. As CO₂ leaks upward out of the injection zone, pressure in the injection reservoir decreases and pressure in the overlying aquifers increases. We present one such simulation here to illustrate the point that the relative pressure response could be much larger and more easily detected in the reservoir than in overlying aquifers. In the future, we will apply the method described above to calculate the probability that a monitoring well network would detect such a leakage 'event'.

Our method requires specification of minimum threshold changes in water quality or pressure that would be considered 'detectable'. In practice, this threshold would be determined by precision of sensors and/or laboratory analytical equipment, as well as background variability or noise. For a thorough discussion of these factors, see [5,14]. In this study, we assume the minimum measurable pressure head change in the shallow aquifer is 2 cm (~200 Pa). The detectable pH threshold was defined as 6.6, based on a study of background variability of pH for the Edwards Aquifer [14].

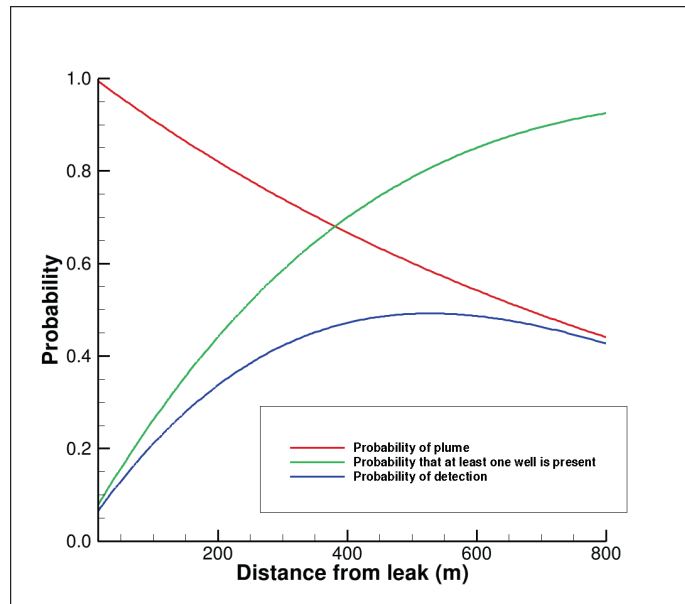


Figure 1. Idealized factors affecting leakage detection probability

3. Results

3.1. Shallow aquifer leakage scenarios

The first set of simulations [7, 8] were developed so as to represent CO₂ leakage into the base of a small unconfined section of the Edwards aquifer north of San Antonio, TX. Using site specific data [10,11], we specified a very small background hydraulic gradient ($7.65\text{E-}4$), a relatively thin aquifer (150m), and a network of existing water supply wells that could monitored for signs of leakage. These wells have an average density of 3.2 wells/km^2 .

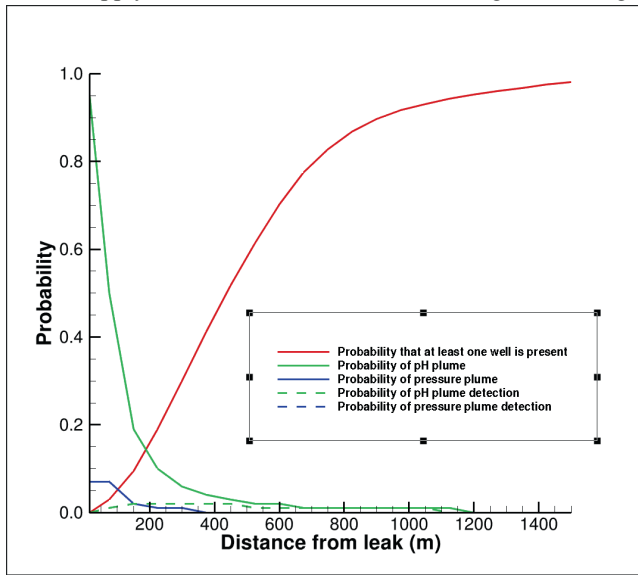


Figure 2. Leakage detection probability using pressure head and water quality monitoring, based on simulations in [7,8]

The second set of Monte Carlo simulations [9] encompassed a larger range of leak rates, and two new aquifer variables: aquifer thickness and background hydraulic gradient. Thicker aquifers with larger hydraulic gradients produced significantly larger dissolved CO₂ plumes with less buoyant free phase. An illustrative example of plume behavior is shown in Figure 3.

Monte Carlo methodology was used to consider a wide range of CO₂ leakage rates and aquifer characteristics such as mean permeability, anisotropy, and statistical parameters of permeability/porosity heterogeneity. Despite the wide range of scenarios considered, the vast majority of simulations were dominated by rapid upward flow of buoyant free-phase (gas) CO₂ and very little lateral migration occurred. For this reason, these plumes would be very hard to detect with the existing network of wells. The average results, shown in Figure 2, illustrate the problem. The red line reflects the spatial arrangement of the wells; for example, at 600m from any arbitrary leakage location there is about a 60% chance of encountering a well. However, due to the geometry of the buoyancy-dominated CO₂ plumes, the chance of encountering a plume declines to less than 20%

200m away from the leak. The chance of encountering a measurable pressure change declines even more rapidly. The overall chance of leakage detection (green dashed line) is always small.

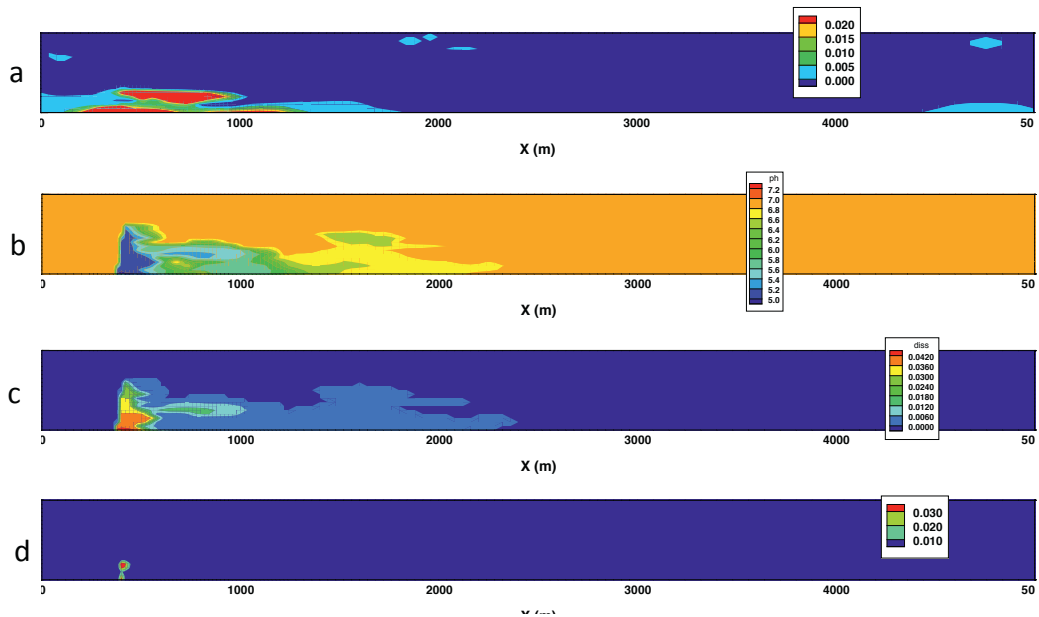


Figure 3. Vertical cross-section through shallow aquifer simulation for 40 years after leakage initiation. a) Pressure head change; b) pH; c) Dissolved CO₂ mass fraction; and d) Free phase CO₂

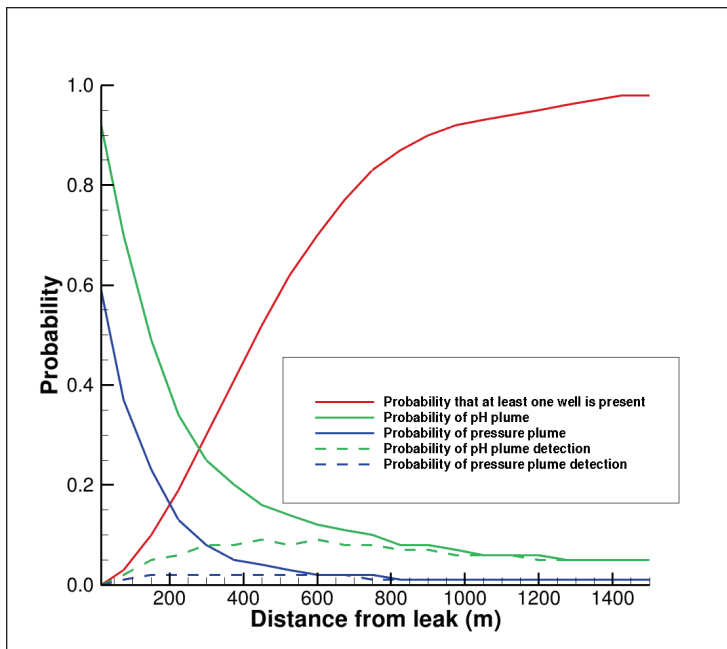


Figure 4. Leakage detection probabilities, based on simulations in [9]

The pH plume (b) is very similar in size and shape to the dissolved CO₂ plume (c). At this site, pH would be a very sensitive indicator of leakage. The dissolved CO₂ plume is much larger than the free-phase (gas) plume (d). The detectable pressure head plume ($\Delta h < 2$ cm) is smaller than the pH plume. The relatively small pressure plume is partly a consequence of unconfined conditions and rapid CO₂ dissolution.

The average of computed probabilities from this set of simulations is shown in Figure 4. Although the chance of detection is larger in this case, probabilities are still fairly small. The maximum chance of detection is approximately 10%.

3.2. Fault rupture scenarios

We consider a scenario of CO₂ injection at a rate of 192 kg s⁻¹ leading to overpressurization of a 100 m thick reservoir at a depth 1000 m, and subsequent failure of a 1000 m long fault, 1200 m distant from the injection well (Figure 5). The fault intersects the reservoir, two aquifers and two caprock units; their respective permeabilities are: reservoir - 125 mDarcy, aquifers - 10 mDarcy, and caprock - 1 μ Darcy. Failure occurs when overpressure at any point on the fault exceeds 1 MPa, at which point permeability is increased to 1 Darcy everywhere on the fault. For this particular configuration, fault failure occurs after 6 months. With the new hydraulic connection to overlying formations, pressure drops in the reservoir and increases in the overlying aquifers. CO₂ also migrates up the fault, changing phase from liquid to gas. Lateral model boundaries are open to flow, although they are sufficiently distant from the injection well and fault location to unduly influence the presented results.

Figure 6A shows the position of the CO₂ plume 6 days after the rupture has occurred and fault permeability increased. CO₂ in the immediate vicinity of the newly permeability fault has starting rising buoyantly, whereas much of the rest of the plume remains undisturbed (at least at this early stage). As expected, Figure 2B shows that pressure decreases have occurred throughout the reservoir, while pressure increases occur above the formation, both inside the fault and in the portion of the formation adjacent to the fault.

Zeidouni and Pooladi-Darvish [3] state that quartz gauges available today, where gauge drift is negligible and tidal effects can be eliminated, have high quality resolution down to 140 Pa. As a conservative measure, we have assumed in Figure 6B that any pressure change – positive or negative – exceeding 300 Pa could potentially be detected by such sensors. The detectable pressure plume is then the area enclosed by the $\Delta P = 300$ Pa contour, in those formations where pressure has increased, i.e., the overlying aquifers. Similarly, in the reservoir where there is pressure decline, the area of pressure disturbance enclosed by the $\Delta P = -300$ Pa contour defines the detectable region. Note, in these definitions, ΔP refers to pressure changes since the fault has ruptured, not since the start of injection.

Of particular interest is the relative size of the pressure disturbances in the overlying aquifers versus the storage reservoir. Detectable pressure decline occurs over a much larger region in the storage reservoir, spanning an area of ~ 18 km² 6 days after the fault has ruptured. In comparison, pressure disturbances in the aquifers are ~ 2 to 4 km²; the smaller footprints of these disturbances are presumably less likely to be detected by a distributed scheme of monitoring wells.

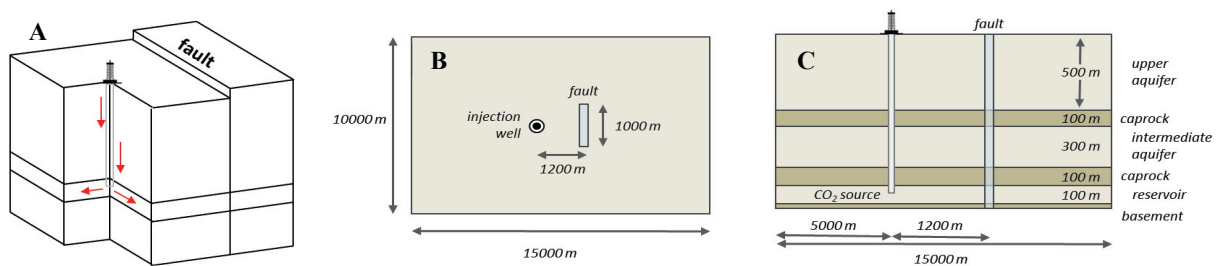


Figure 5: A: Set up of the fault rupture scenario. Fault offset is schematic only. B: Dimensions of system components in horizontal plane. C: Dimensions of system components and modeled geological units in vertical slice.

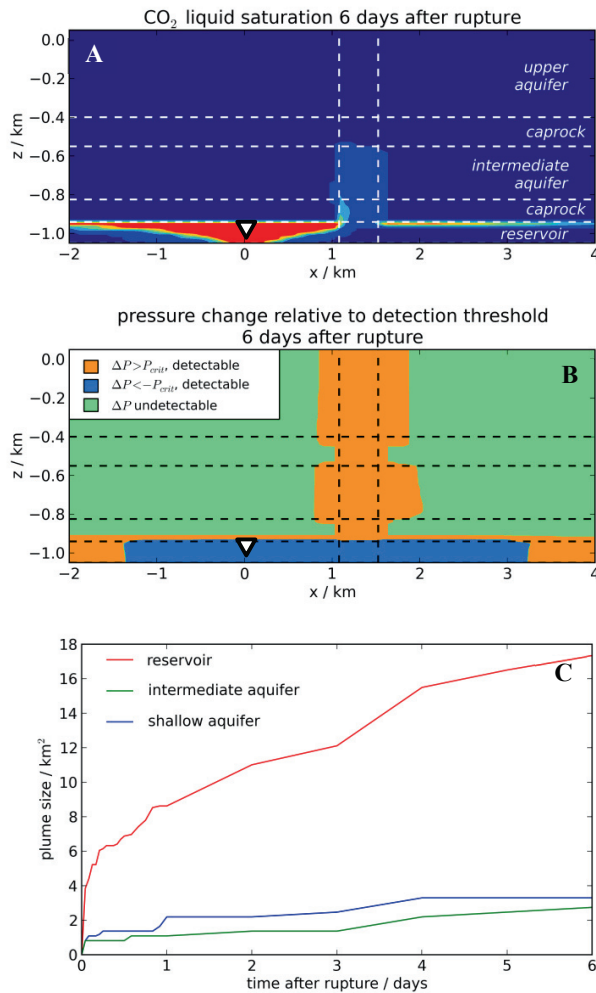


Figure 6: A: Position of CO₂ plume in the reservoir 6 days after fault rupture. The injection location is indicated by a white triangle. B: Pressure changes in the model 6 days after fault rupture. Three regions are defined: detectable pressure increase (orange); detectable pressure decrease (blue); and undetectable pressure changes. The pressure threshold for detection, ΔP_{crit} , is 300 Pa [3]. C: Evolution of the size of the detectable pressure plume in the overlaying aquifers (blue and green) and the area of detectable pressure decrease in the reservoir.

4. Discussion and Conclusions

Results from the shallow aquifer simulations clearly show the inefficacy of point-based measurements (either water quality or pressure) for detecting a CO₂ leak under the range of conditions considered here. The probability of detection is quite low because of several factors, including the well density (relative to plume size) the unconfined conditions and, most importantly, our assumption that the leak would emerge in a random location. If *a priori* information were available to predict the most likely locations for leakage, detectability probabilities could be significantly increased. However, it is always possible that leakage would emerge in unexpected locations, as was the case in a recent controlled release study [6].

Preliminary results show that, at least for some scenarios, pressure monitoring in the injection reservoir would be much more effective in signaling that a leak has initiated. Importantly, the area of detectable pressure decline in the storage reservoir extends sufficiently far from the fault to include the injection well. This suggests that installation

and monitoring of pressure gauges in the injection well itself may be sufficient to detect the development of new leakage pathways (notwithstanding the difficulty of a noisy pressure signal near the injection well due to a non-steady injection rate.) Furthermore, for an injection operation comprising multiple wells, downhole pressure monitoring at the various sites could be sufficient to triangulate the position and properties of the leak, as has been suggested for configurations of monitoring wells [e.g., 4, 15]. The advantage here is that the considerable expense and effort to drill and complete a series of injection wells can be leveraged to “piggy-back” a set of monitoring stations.

As a final note, the proposed system for detecting the occurrence of new caprock breaches by monitoring in the storage reservoir does not require a reliable forward model for reservoir pressure evolution. Alternative methods, such as the approach of [15] rely on comparing modeled and observed pressure evolution, with appropriate errors and uncertainty considered; any deviation between observation and expectation suggests the presence of a leakage pathway. They assume that model uncertainty is sufficiently large in the reservoir that this approach would yield poor performance in this formation; overlying aquifers do not suffer from this drawback and monitoring these formations is therefore preferable. Our approach, by jettisoning the requirement of a forward model, can be applied to either reservoir or aquifers, with reservoirs being preferable for their more extensive pressure signal. However, as our approach requires detection of a change in the trajectory of pressure evolution, e.g., a shift from pressure increase to pressure decline at the injection well, we are limited to detecting leakage pathways that are created during the monitoring period. Pre-existing pathways will not be discovered.

While this method does not necessarily identify the location or magnitude of the leak, it could be used as a trigger to implement pressure management or other mitigation strategies. Further work is necessary to identify the exact range of conditions that reservoir pressure monitoring would be effective, especially if injection rates are unsteady.

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